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Preliminary Assessment of Costs and Credits for Hazardous Waste Co-Firing in Industrial Boilers

Acurex Corp., Mountain View, CA

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This report provides preliminary information on the costs and credits associated with hazardous waste co-firing in industrial boilers. The main objective is to identify and evaluate the costs/credits inherent in current hazardous waste co-firing practices, plus the additional costs that may be incurred as a result of more stringent emissions limitations.

An overview of current hazardous waste/industrial boiler co-finring practices is provided. This overview addresses the types of waste now being burned in boilers, the generic designs and capacities of boilers now being co-fiered, and the types of air pollution control device (APCD) retrofits that may be required in the advent of air emissions regulations. Parametric cost estimate methods are provided for: (1) waste handling equipment addition, (2) combustion system retrofit, (3) APCD retrofit, (4) incremental O&M costs, and (5) fuel savings and waste disposal credits. The cost estimating approach is designed to account for differences in waste characteristics, boiler design, capacity, and waste/fuel co-firing ratio. Finally, cost/credit calculations are presented for two hypothetical waste co-firing scenarios. These calculations are presented to illustrate how the information provided in this report can be used; no conclusions concerning the economy of waste co-firing are intended.

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PRELIMINARY ASSESSMENT OF COSTS AND CREDITS FOR HAZARDOUS WASTE CO-FIRING IN INDUSTRIAL BOILERS

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FOREWORD

Today's rapidly developing and changing technologies and industrial products and practices frequently carry with them the increased generation of solid and hazardous wastes. These materials, if improperly dealt with, can threaten both public health and the environment. Abandoned waste sites and accidental releases of toxic and hazardous substances to the environment also have important environmental and public health implications. The Hazardous Waste Engineering Research Laboratory assists in providing an authoritative and defensible engineering basis for assessing and solving these problems. Its products support the policies, programs and regulations of the Environmental Protection Agency, the permitting and other responsibilities of State and local governments and the needs of both large and small businesses in handling their wastes responsibly and economically.

This report provides preliminary information on the costs and credits associated with burning hazardous wastes along with conventional fuels for steam generation in industrial boilers. The main objective is to identify and evaluate the costs/credits inherent in current hazardous waste co-firing practice, plus the additional costs that may be associated with more stringent emissions limitations. This information is intended primarily for EPA use in assessing the cost/benefit trade-offs for increased regulation of hazardous waste co-firing in boilers. However, it may also be useful to other individuals or organizations interested in the economics of hazardous waste utilization as fuel. For further information, please contact the Alternative Technologies Division of the Hazardous Waste Engineering Research Laboratory.

David G. Stephan, Director
Hazardous Waste Engineering Research Laboratory

ABSTRACT

The U.S. EPA, Office of Solid Waste (OSW) is currently assessing the need for and the consequence of regulating emissions from industrial boilers co-firing hazardous wastes with conventional fuels. This Regulatory Impact Analysis (RIA) is intended to determine representative air pollutant emission rates for boilers currently co-firing hazardous wastes, evaluate the nature and extent of emissions limitations that may be needed, and assess the overall cost/benefit tradeoffs of various regulatory approaches. A key element of this RIA is an assessment of the potential costs to industry for hazardous waste co-firing regulation.

This study is intended to provide preliminary information on the costs and credits associated with hazardous waste co-firing in industrial boilers. The main objective is to identify and evaluate the costs/credits inherent in current hazardous waste co-firing practice, plus the additional costs that may be incurred as a result of more stringent emissions limitations.

In order to establish a basis for the cost/credit information, an overview of current hazardous waste/industrial boiler co-firing practices is provided. This overview addresses the types of wastes now being burned in boilers, the generic designs and capacities of boilers now being used for co-firing, and the types of air pollution control device (APCD) retrofits that may be required in the advent of air emission regulations. The most probable waste/boiler/APCD retrofit scenarios are emphasized.

Based on these scenarios, parametric cost estimating methods are provided for: (1) waste handling equipment addition, (2) combustion system retrofit, (3) APCD retrofit, (4) incremental O&M costs, and (5) fuel savings and waste disposal credits. The cost estimating approach is designed to account for differences in waste characteristics, boiler design, capacity, and waste/fuel co-firing ratio. This is important because the economics of hazardous waste co-firing can differ widely from one situation to another.

Finally, cost/credit calculations are presented for two

hypothetical waste co-firing scenarios. These calculations are presented to illustrate how the information provided in this report can be used; no conclusions concerning the economy of waste co-firing are intended.

This report is submitted in fulfillment of Contract 68-02-3176 by Acurex Corporation, Energy & Environmental Division, under the sponsorship of the U.S. Environmental Protection Agency. This report covers the period July 1, 1983, to October 15, 1983, and work was completed as of October 15, 1984.

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CONVERSION FACTORS

To convert from	To	Multiply by
Btu	Kcal	0.2520
°F	°C	(°F-32)/1.8
ft	m	0.3048
ft^2	m^2	0.09290
ft^3	m^3	0.02832
gal	lit	3.785
gr	mg	64.80
hp	kw	0.7457
in	cm	2.540
in WC	kPa	0.2487
lb	kg	0.4536
psi	kPa	6.895

SECTION 1

INTRODUCTION

BACKGROUND

Over the past decade, waste co-firing in boilers designed for fossil fuel combustion has become increasing attractive and widespread in the industrial sector. The four-fold increase in fuel oil prices during the early 1970's, and subsequent increases in other fossil fuel prices have provided a strong impetus for waste co-firing to reduce steam generation costs. This economic incentive for burning wastes in conjunction with fossil fuels, particularly hazardous wastes, has been increased dramatically by the passage of the Resource Conservation and Recovery Act (RCRA) in 1976. The strict RCRA requirements for landfilling hazardous wastes, especially hazardous liquids, have substantially increased waste disposal costs. Because many hazardous liquid wastes are fuel-quality materials, co-firing these wastes provides the dual advantage of reduced fuel costs for steam generation, and elimination of an expensive waste disposal problem. Hazardous waste co-firing also supports the RCRA goal of maximum resource use and reuse.

Since January 1981, incinerators burning hazardous materials for the stated purpose of waste disposal, rather than energy recovery, have been subject to RCRA performance standards for (1) destruction and removal efficiency (DRE) of principle organic hazardous constituents of the waste (POHC's), (2) particulate loading in the flue gas, and (3) HCl removal efficiency. The specific requirements are $\geq$ 99.99% DRE for each POHC in the waste mix, $<$ 0.08 gr/dscf particulate in the flue gas, and $>$ 99% HCl removal efficiency. Currently, these standards do not apply to boilers burning hazardous wastes for the stated purposes of fuel substitution and energy recovery.

The Office of Solid Waste (OSW) of EPA is currently assessing the need for, and consequences of, regulating emissions from industrial boilers co-firing hazardous wastes with conventional fossil fuels. This Regulatory Impact Analysis (RIA) is intended to determine: (1) the current performances of industrial boilers

co-firing hazardous wastes, particularly with respect to POHC destruction, (2) the nature and extent of emissions limitations that may be needed to protect human health, (3) the economic impacts of such emissions limitations, and (4) the overall cost/benefit tradeoffs associated with various regulatory approaches.

Thus, a key element of the RIA is the assessment of potential costs and credits associated with hazardous waste co-firing in industrial boilers.

OBJECTIVES AND SCOPE

This study is intended to provide a preliminary assessment of the costs and credits associated with the hazardous waste co-firing in industrial-scale boilers used for steam generation. The main objective is to identify and evaluate the costs/credits inherent in current hazardous waste co-firing practice, plus the additional costs that may be associated with more stringent emissions limitations. The second objective was to provide methods to parametrically estimate these costs and credits as a function of boiler design and capacity, waste quantity and composition, and regulatory requirements. Because many of the costs and credits associated with hazardous waste co-firing are extremely site-specific, the secondary objective of parametric economic analysis cannot be fulfilled within the limitations of this study. While certain costs and credits can be estimated on a generic basis, many of the economic impacts can only be assessed by collecting and analyzing historical cost data. This will require a much more in-depth study.

The following section of this report discusses current hazardous waste co-firing practices in terms of the industrial boiler population, waste quantities, and waste characteristics. This information is based on seven studies conducted by Acurex Corporation for EPA on the technical and environmental aspects of boiler/waste co-firing (References 1-7). Potential air pollution control system additions for particulate and/or HCl emission control are also discussed.

Section 3 presents qualitative and (where possible) quantitative information on the capital requirements to retrofit fossil fuel boilers for hazardous waste co-combustion. Waste storage and handling facilities, combustion system modifications, and air pollution control device (APCD) additions are all addressed.

Section 4 addresses incremental operation and maintenance (O&M) costs that may be associated with waste co-firing. These include additional power, water, chemical, residue disposal, maintenance, and waste analyses requirements. The discussion is largely qualitative due to the site-specific nature of many of

these costs. However, quantitative guidelines are presented where possible.

The credits associated with hazardous waste co-firing are discussed in Section 5. These include the obvious fuel conservation credit, plus the elimination of alternative waste disposal costs.

A format to summarize co-firing costs and credits is presented in Section 6.

Finally, Section 7 presents cost/credit evaluations for two hypothetical waste co-firing scenarios. These evaluations are presented to illustrate how the information contained in Sections 3-5 may be used, and the limitations of this information with respect to projecting overall profitability or loss. These hypothetical evaluations are not intended as general perspectives on the economic feasibility of hazardous waste co-firing in industrial boilers. As previously stated, this study is only intended to (1) identify the various costs and credits associated with co-firing, and (2) provide methods to estimate these costs (where possible) for differing generalized scenarios.

SECTION 2

HAZARDOUS WASTE CO-FIRING PRACTICES

Statistical data on the industrial boiler population within the U.S., hazardous waste generation data by wastetype and industry, and information on known hazardous waste/boiler co-firing sites are detailed in References 1 and 2. The conclusions drawn from these data compilations pertinent to this study are summarized in the following subsections. These conclusions on current hazardous waste co-firing practices serve as the basis for the cost analyses presented in Sections 3 through 5.

WASTE CHARACTERISTICS AND CO-FIRING RATIOS

The vast majority of hazardous wastes co-fired in industrial boilers are liquids, either at ambient temperature or at typical No. 6 fuel oil preheat temperature (150 to 225°F). The main reason for this is simply that most waste streams defined as hazardous under RCRA are liquids rather than solids. Liquids are also more amenable to boiler co-firing from the standpoint of storage and handling feed system compatibility, bottom ash handling, and particulate control. While liquids can usually be stored, pumped, and atomized into the furnace in much the same manner as distillate or residual fuel oil, hazardous solid waste (e.g., sludges) often present specialized storage, conveying, and feeding problems. Boilers originally designed to fire gas or fuel oil (i.e., the vast majority of boilers in the chemical industry) usually do not have adequate bottom ash handling capability for solid wastes, even relatively finely divided solids pneumatically conveyed and fired in suspension. Particulate emissions are also a much greater problem with solid wastes than liquid wastes. These factors do not preclude hazardous solid waste co-firing in boilers, but they do render these materials much less desirable candidates than liquid wastes.

The majority of liquid by-product fuels co-fired in boilers are oily wastes, contaminated solvents, and process wastes from the chemical and related industries. These wastes usually have desirable fuel quantities such as gross heating values greater than 8000 to 10,000 Btu/lb, water contents less than 20 to 30%, ash contents less than 0.5%, and chlorine concentrations less than

approximately 1 to 2%. Wastes with such properties are the most desirable for co-firing purposes because they can be fired through conventional oil burners and substituted almost quantitatively for fuel oil or gas with negligible efficiency losses. However, wastes with less desirable properties can be, and are, co-fired in industrial boilers. Two extreme cases in point are: (1) a small firetube boiler facility burning a dilute (less than 1% organics) wastewater stream in conjunction with natural gas, and (2) a larger firetube boiler facility with a special scrubbing system designed to handle wastes containing more than 50% chlorine.

Like waste compositions, waste/fuel firing ratios vary from one extreme to the other, i.e., less than 5% to more than 90% of the heat input attributable to waste combustion. In most cases observed to date, however, waste co-firing contributes 10 to 50% of the gross heat input. The higher waste fuel ratios generally occur during reduced load periods. This is due to the common practice of baseloading waste while modulating fuel to accommodate load swings. When sub-fuel quality wastes are co-fired, waste feed cutoff below a certain minimum load (e.g., 25 to 50%) is not uncommon.

Obviously, boiler capacity and required steam production rates vs. on-site waste generation rates play an important role in determining waste/fuel firing ratios. Wastes are usually burned at the maximum feasible rate when available, given equipment design and efficiency loss limitations. When wastes are unavailable, 100% conventional fuel is burned.

An implicit assumption here is that only wastes generated inhouse are burned. Most firms outside the commercial waste disposal business do not make a practice of accepting off-site wastes, although there are a few exceptions.

INDUSTRIAL BOILER CHARACTERISTICS

Most industrial boilers which are currently co-firing hazardous wastes, or are likely to co-fire wastes in the future, were originally designed for natural gas and/or fuel oil combustion. This is particularly true in the chemical industry. The most common design types and capacity ranges are as follows:

(1) Scotch firetube, N-pass design, packaged boilers for natural gas, distillate oil, or combination gas/distillate oil firing. Single burner design, with no economizer or air heater. Typical capacities are 10,000 to 30,000 lb/hr steam, up to 50,000 lb/hr steam.[a]

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[a] 1000 lb/hr steam is approximately equivalent to 1 million Btu/hr

(2) Watertube design for natural gas, distillate oil, or gas/distillate/residual oil firing (with oil preheat equipment). Single or multiple burner design. Steam capacities of 20,000 to 100,000 lb/hr, saturated at 125 to 250 psig design rating. Economizers not atypical at more than 50,000 lb/hr steam, but air heaters rare.

(3) Watertube design with multiple burners for gas/oil firing. Steam capacities of 100,000 to 250,000 lb/hr and up, with turbogenerator steam pressures and superheat in the larger size ranges. Economizers typical, and possibly air heaters.

These boiler designs are most common for liquid waste co-firing, however, coal-fired boilers are also being utilized to burn certain liquid and (possibly) solid hazardous wastes. The basic coal-fired boiler types fall into two categories:

(1) Stoker-fired boilers, primarily spreader stokers, although underfeed, retort, and chain grate stokers are still in service. Typical capacities are 50,000 to 150,000 lb/hr steam, up to 300,000 lb/hr steam. All designs are suitable for liquid waste co-firing, with front-wall burner addition.

(2) Pulverized coal-fired boilers, primarily in the largest industrial boiler size range -- 250,000 lb/hr steam and up. All designs are suitable for liquid waste co-firing by individual burner replacement.

AIR POLLUTION CONTROL CONSIDERATIONS

With few exceptions, existing gas and/or oil fired boilers are equipped with no air pollution control devices (APCD's). Stoker and pulverized coal-fired boilers are usually provided with multiclones, although larger pulverized coal-fired boilers may be equipped with electrostatic precipitators (ESP's). A few existing large industrial boilers are equipped with fine particulate and acid gas absorption devices.

SECTION 3

CAPITAL REQUIREMENTS

As indicated in the preceding section, one of the baseline assumptions of this study is that boilers co-firing hazardous wastes were originally designed to burn one or more conventional fossil fuels -- natural gas, oil, or coal. Therefore, an initial capital investment is required to retrofit a boiler for waste co-firing. This capital investment can be divided into three components:

(1) Addition of waste storage and feeding equipment,

(2) Boiler modification to accommodate the waste fuel, and,

(3) Air pollution control device addition for particulate/HCl removal, if required by regulation.

The total investment for retrofit is usually relatively modest, unless air pollution control device addition is mandated.

WASTE HANDLING AND FEEDING EQUIPMENT

In the cases observed to date, liquid wastes are transported from the process area to the boiler location by tank truck and pumped into a settling tank, or holding tank. If the boiler is within reasonable proximity to the processing area where the waste is generated, direct pumping to the settling or holding tank is also feasible. A separate settling tank is good design practice in either case, if the waste contains settleable solids. Otherwise, only holding, or storage, tanks are needed.

If the waste is delivered by tank truck, a single 5000 gal holding tank is usually sufficient. This capacity will handle a typical tank truck load, and will provide at least 8-hr storage for a large industrial boiler co-firing waste at the ratios described in section 2, assuming a waste heating value approaching fuel quality (i.e., 10,000 Btu/lb). In some cases, however, a larger or more diverse storage capacity may be desirable. If the waste is pumped directly from the process area on a continuous basis, a 10,000 gal or even a 20,000 gal storage tank may be

desirable for equalization if waste co-firing is terminated during low load periods. These larger storage capacities are also desirable if the waste is generated intermittently; thus enabling continuous or extended waste co-firing campaigns. In the event of individual waste stream incompatibility, multiple storage tanks may also be required.

All these factors must be considered in estimating total storage tank capacity for a given site situation. Costs for individual 5,000, 10,000, and 20,000 gal tanks designed for hazardous liquid waste storage are presented in Table 1. The assumptions behind these costs are:

* Aboveground, vertical, conical roof, top fill/bottom discharge design of carbon steel construction.

* Equipped for agitation, heating, nitrogen blanketing, and flame arrest.

* Freight and installation labor costs included.

* No substantive site preparation required.

From the storage tank, wastes are usually pumped directly to the boiler through self-cleaning filters or dual, parallel strainers or cartridge filters. Recirculatory flow to maintain constant nozzle pressure on turndown is unnecessary because wastes are normally baseloaded. Therefore, waste feed rate requirements rarely exceed 10 gpm. Gear pumps in this size range usually cost $1000 to $1500, including motors, starters, foundations, and wiring, plus installation labor. Dual feed pumps are desirable to provide redundancy in the event of equipment failure.

Nominal 1-in diameter piping is suitable for virtually all waste co-firing systems. Schedule 40, carbon steel, 1-in diameter pipe typically costs $22/ft with reasonable allowances for valves, fittings, insulation, hangers, and installation labor. Total piping length is site specific, although 100 to 200 ft per waste feed system is a conservative estimate. Costs for in-line filter systems can range from several hundred to several thousand dollars, depending on complexity and service requirements.

With the exception of in-line solids filtration and (possibly) settling for solids/water removal, very little if any waste pretreatment is performed in co-firing facilities.

BOILER RETROFIT

In many co-firing situations, retrofit at the boiler is a relatively minor consideration. In other situations, complete burner system replacement may be necessary.

TABLE 1. WASTE STORAGE TANK COSTS (DECEMBER 1982)

Tank capacity (gal)	Installed cost ($)
5,000	34,000
10,000	46,000
20,000	61,000

For most firetube or watertube boilers with single burners designed for combination gas/oil firing, the only needed modifications are oil gun replumbing for waste injection and minor control system changes. With these modifications, liquid waste can be baseloaded through the centerline fuel gun while natural gas is fired through the outer ring to maintain the desired boiler load. Under reduced load conditions, waste firing would (probably) be terminated and either fuel oil or gas alone would be burned. The costs for these types of modifications are highly case-specific, but are usually substantially less than complete burner replacement.

A second alternative for boilers equipped with single burners (oil or gas/oil) is to install a pre-mix system for waste and fuel oil upstream from the fuel feed system, and thus operate the boiler on a consistent mix of waste and fuel oil fired through the existing oil gun. However, this is usually feasible only if (a) the waste is homogeneous, and (b) the waste and fuel oil are miscible and compatible with respect to viscosity, volatility, etc. Otherwise, serious combustion control problems are likely.

A third alternative for large single burner systems (e.g., large dual air register, combination gas/oil burners) is to install one or more liquid waste guns in the burner air register and simply atomize the waste into the primary fuel flame envelope. This can provide more flexibility in terms of waste/fuel firing ratios and load adjustment, but can also cause flame stability problems if the waste injection system is not fine-tuned.

The fourth alternative is to replace the entire burner with a model specifically designed to accommodate liquid waste co-firing with oil and/or gas. This is the most expensive alternative in terms of initial capital investment, but may be the preferred choice with respect to long-term operating efficiency and maintenance considerations. In some cases, it may be the only viable alternative depending on the waste characteristics, desired waste/fuel firing ratio, existing burner design, peak load

requirements, and load fluctuations. The decision criteria for burner system modification (as described above) vs. replacement are extremely case-specific.

In general, the larger multiple-burner watertube boilers designed for oil or gas/oil firing provide more flexibility in terms of retrofit for waste co-firing than do single burner boilers. The common practice is to baseload waste through one (or more) of the existing oil burners, while firing oil (or gas) through the remaining burners to control boiler load. This approach is usually effective, with the possible exception of low-Btu waste co-firing during peak demand. If the boiler cannot meet peak load requirements with one burner devoted to waste firing, it may be necessary to (1) terminate waste firing during these periods and dedicate all burners to primary fuel, or (2) modify one of the burners for combination waste/fuel introduction as discussed for single burner systems. Again, the deciding factors are situation specific.

In boilers equipped only with single or multiple ring burners for natural gas, liquid waste co-firing can be effected by plumbing a liquid waste gun into the burner centerline in much the same fashion that natural gas burners are retrofitted for fuel oil firing. Of course, liquid fuel train addition and combustion control modifications are necessary. The obvious alternative is burner replacement.

Thus, the retrofit requirements for gas, oil, or combination gas/oil fired boilers to co-fire liquid wastes can range from simple oil line replumbing for waste introduction, to liquid waste gun addition with minor control system adjustments, to complete burner replacement. Both the retrofit requirements and the associated costs are case-specific. Obviously, the larger initial costs are associated with complete burner replacement.

However, the highest retrofit costs are usually associated with stoker or pulverized coal-fired boiler conversion for liquid waste firing. In addition to complete new burner assemblies, a thorough combustion system overhaul -- blower, damper, and control instrumentation -- is usually required.

Due to the many design variables involved, and site specific factors, it is impossible to generalize the costs for boiler co-firing retrofit. However, Figure 1 illustrates how these costs can vary depending on the retrofit requirements. Vendor-specified equipment costs are provided as a function of capacity for three retrofit scenarios.

The lower curve in Figure 1 applies to one of the simplest retrofit cases: liquid waste nozzle addition/replacement. The costs for this case are for nozzles only; total installed costs

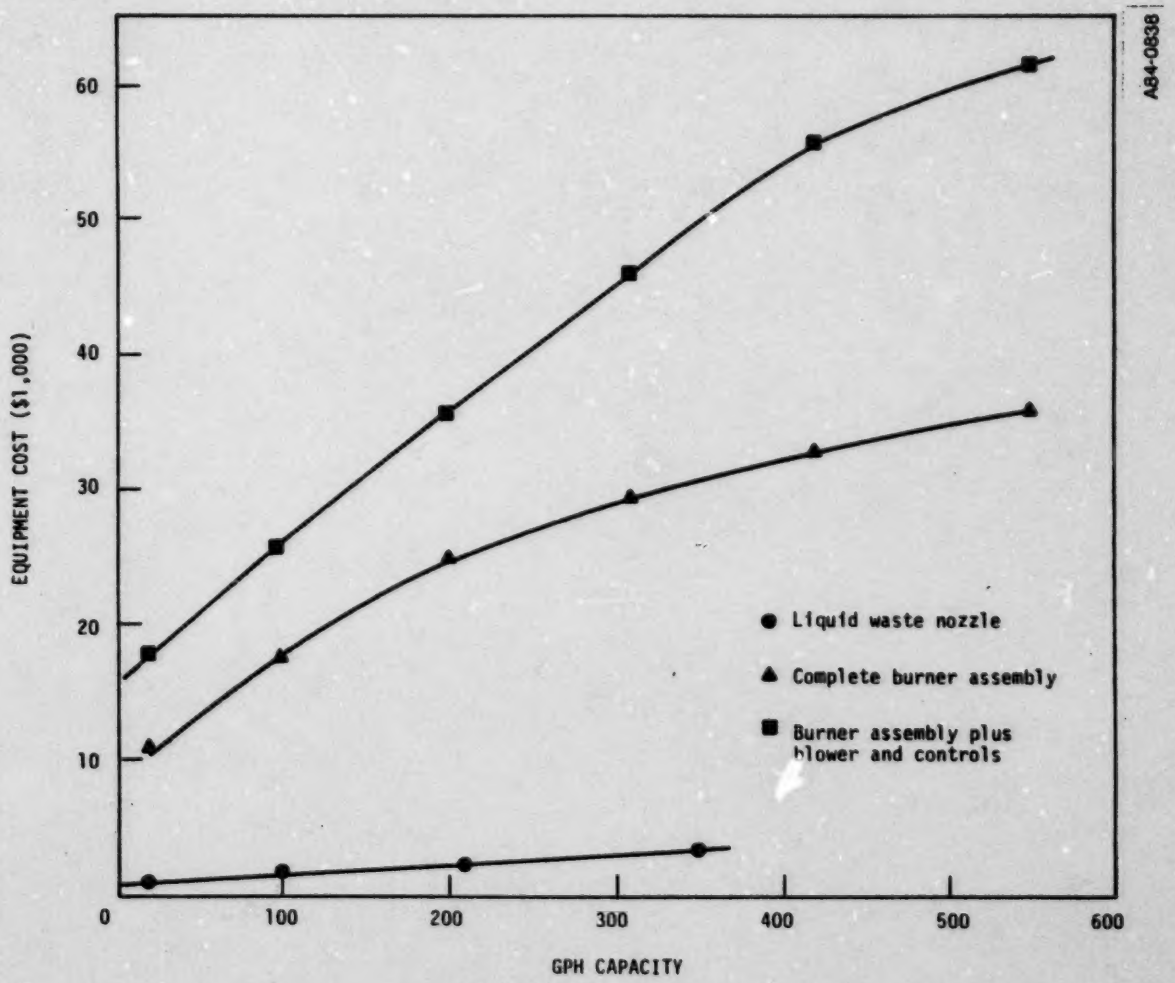

Figure 1. Burner Component and System Costs (July 1982)

including pressure and flow control valves, plus labor, can easily run two to three times the costs for the nozzles alone.

The middle curve is for complete liquid fuel burner assemblies with natural gas firing capability built-in. The costs include pilot, spark ignition assembly, and damper assembly. The upper curve is for complete burner systems, including forced-draft blowers and master controls for flame safeguard, fuel modulation, air pressure and flow regulation.

Installation costs for burners and complete burner systems are typically 50% of the equipment cost. If structural modifications are required to install the burner, this installation cost can easily double.

AIR POLLUTION CONTROL DEVICE (APCD) ADDITION

As indicated in Section 2, industrial boilers designed for natural gas or fuel oil firing are generally not equipped with any APCD's, including boilers co-firing hazardous liquid wastes. If Federal standards similar to the RCRA Part 264, Subpart O, performance standards were to be promulgated for boilers co-firing hazardous waste, it is likely that at least some boiler facilities would need to provide one or more APCD's for particulate and/or HCl removal. Obviously, this would depend on the ash content of the waste, chlorine content of the waste, and the regulatory requirements imposed.

It is impossible to predict industry trends relative to APCD addition at this point, should performance standards for particulate and/or HCl be promulgated. However, six scenarios can be envisioned:

(1) The waste being co-fired at the site in question contains negligible ash and chlorine, so APCD addition is unnecessary to comply with regulatory requirements.

(2) Chlorinated wastes are not being burned at the site, but particulate emissions exceed the standard as a result of waste co-firing. The mandated particulate removal efficiency is in the 95 to 99% range. In this case, a "cold-side", dry electrostatic precipitator (ESP) is the likely choice for particulate control.

(3) This scenario is identical to the previous one, except that the mandated particulate removal efficiency is more than 99.5%. In this case, a baghouse would probably be more economical than an ESP for particulate control due to the excessive plate area required for an ESP to achieve this efficiency. This is a generalization, however, which could be reversed by site-specific factors.

(4) The co-fired wastes do not contain significant ash, but chlorine is present in quantities such that the waste/fuel mix contains more than 0.5% organically-bound chlorine. In this case, a packed bed absorption system may be required for HCl removal. This is not considered a typical waste co-firing scenario, due to the adverse boiler corrosion impacts associated with burning chlorinated materials.

(5) The co-fired wastes contain significant ash and chlorine, such that particulate and HCl emission standards would both be violated. In this case, a venturi scrubber/packed bed absorption system would be the likely choice for air pollution control. Again, this is not considered a typical waste co-firing scenario because of boiler corrosion problems.

(6) Either particulate or HCl emission standards are exceeded, but the boiler facility owner/operator chooses to eliminate waste co-firing rather than install the necessary air pollution control equipment.

These scenarios apply specifically to natural gas/fuel oil-fired boilers, but also to coal stoker-fired boilers in principle because stokers are usually equipped with no more than cyclonic separators for particulate control.

The following subsections present cost information for addition of each of the APCD's discussed above.

Electrostatic Precipitators

Electrostatic precipitators are one of the most common particulate control devices used on large utility-scale boilers. They can be used at temperatures as high as 1000°F although they rarely are used to control particulate in gas streams above 700°F. They typically have a high particulate collection efficiency at a low pressure drop. As a result, they do not require new fans or other gas handling equipment and are especially well suited for retrofit applications such as small, industrial boilers co-firing waste.

The cost of the basic electrostatic precipitator is a function of the plate area which, in turn, is a function of the required efficiency. The electrical characteristics of the dust, quantified by the drift velocity, have a large effect on the collection efficiency and plate area, and consequently, on the cost of the precipitator. The resistivity of the dust varies with the temperature and moisture content of the gas, therefore, in some applications, auxiliary equipment may be required to precondition the gas stream prior to entering the precipitator. The addition of moisture in the gas stream together with low

operating temperatures will necessitate insulating the precipitator to prevent condensation and subsequent corrosion problems. The cost of the basic precipitator is therefore separated into insulated and non-insulated units.

Special cost factors can be incurred in the type of power supply such as automatic voltage control, number of individual sections energized, type of rectifier, etc., and also in special materials of construction and special plate design. These factors are additive costs to the basic collector price and represent custom features either required by the process or by the buyer's specifications.

For the application discussed here, the cost of an electrostatic precipitator can be estimated by (References 8-9):

$$C = 129{,}400 + 4.42\,A \qquad (1)$$

for non-isulated precipitators, and

$$C = 201{,}000 + 6.62\,A \qquad (2)$$

for insulated precipitators, where

C = cost in June, 1983 dollars (Reference 10)

A = collection plate area, ft^2

The insulated ESP cost estimating formula is appropriate if waste co-firing significantly lowers the dew point of the combustion gas, and/or if higher halogen or sulfur concentrations are present in the waste than in the original primary fuel.

The plate area can be calculated using the Deutsch equation (Reference 11):

$$A = -q\,(\ln(1-n))/w$$

where q = combustion gas flow rate, ft^3/s

n = fractional collection efficiency

w = particle drift velocity, ft/s

The combustion gas flow rate is a function of the waste/fuel composition and firing rate, excess air level, and gas temperature at the precipitator inlet. Standard guidelines are available to estimate combustion gas flow for conventional fuels; however, these guidelines do not apply to waste co-firing situations where the waste composition is substantially different than that of fuel oil, natural gas, or coal. Section 3 of Reference 12 presents

calculation methods for combustion gas flow from non-conventional combustion systems.

The required fractional collection efficiency depends on the particulate loading in the combustion gas at the ESP inlet, and the outlet loading specified by Federal, State or local regulations. Methods to estimate the initial particulate loading, and the required fractional collection efficiency, are provided in Reference 12.

The particle drift velocity depends on electric field strength in the precipitating and charging zones of the ESP, the combustion gas viscosity, and the dielectric properties of the particles themselves. For the initial cost estimating purposes of this study, a range of 0.1 - 0.3 ft/s be assumed for the drift velocity (Reference 11).

Installation costs for ESP's are approximately equal to the purchase cost of the basic equipment calculated from equation 1 or 2 (Reference 8-9). These installation costs include the foundations and supports, erection materials and labor, instrumentation and controls, electrical, piping, insulation, painting, and freight.

Fabric Filters

Fabric filters or baghouses are also used to control particulate emissions from boilers, particularly when extremely efficient collection is required. The factors which influence the cost of a baghouse system are:

(1) Type of system used:

- Intermittent pressure, mechanical shaker cleaning
- Continuous pressure, pulse jet cleaning
- Continuous pressure, mechanical shaker cleaning
- Continuous pressure, reverse air cleaning

(2) Type of bags (filter medium) used. The nominal operating temperatures of various fabrics are:

Cotton	180 °F
Nylon	200 °F
Acrylic, polyester	275 °F
Nomex	425 °F

Teflon	400°F
Fiber glass	550°F

(3) Insulation requirements to prevent condensation,

(4) Required cloth area, and,

(5) Standard vs. custom design.

The gases from a boiler burning hazardous waste must be kept above their dew point in order to prevent acid gas condensation in the filter system, ductwork, and auxiliary equipment. As a result, it is usually necessary to use high temperature fabrics such as Nomex, or glass fiber. At these temperatures, it will not be necessary to use stainless steel; however, it will be necessary to insulate the system to prevent acid condensation on the walls.

An important factor in the cost of the baghouse system is the "air-to-cloth" ratio for the system. The higher the ratio, the less filtering area is required for the system; however, this results in a higher cloth usage and higher fan power requirements. Typical ratios that have been evaluated for coal fired boilers range between 1.6 and 3.0 acfm/ft^2 (Reference 13).

The following procedure may be followed to estimate the cost of a fabric filter add-on:

(1) Using the actual gas flow rate from the boiler and an air-to-cloth ratio value given in Table 2, estimate the net fabric area required.

(2) Using the equations given in Table 2 for the appropriate type of equipment, determine the costs of the basic baghouse (standard design) and the insulation add-on.

(3) From Table 3, determine the gross cloth area from the net cloth area.

(4) Determine the bag cost by multiplying the gross cloth area by the cost per square foot given in Table 2.

(5) Determine the total purchase cost by summing the costs for the basic equipment, insulation add-on, and the bags themselves.

TABLE 2. COSTS OF BAGHOUSES (JUNE 1983)

Type	Air to cloth ratio	Bag cost, $/ft^2		Basic equipment cost, $
Mechanical shaker	1.6	Nomex	1.65	Basic C = 9960 + 5.2 A
		Glass	0.67	Insulation C = 3415 + 2.7 A
Pulse jet	2.0	Nomex	1.95	Basic C = 8043 + 11.4 A
		Glass	0.63	Insulation C = 7354 + 3.6 A
Reverse air	3.0	Nomex	1.56	Basic C = 38,500 + 4.5 A
		Glass	0.63	Insulation C = 16,800 + 2.5 A

C = cost in June, 1983 dollars (Reference 8-10, 13)

A = net cloth area, ft^2

TABLE 3. APPROXIMATE GUIDE TO ESTIMATE GROSS CLOTH AREA (REFERENCES 8-9)

Net cloth area, ft^2	Gross cloth area, ft^2
1-4000	Multiply by 2
4001-12,000	1.5
12,001-24,000	1.25
24,001-36,000	1.17
36,001-48,000	1.125
48,001-60,000	1.11
60,001-72,000	1.10
72,001-84,000	1.09
84,001-96,000	1.08
96,001-108,000	1.07
108,001-132,000	1.06
132,001-180,000	1.05
over 180,000	1.04

Costs for installation and auxiliaries are usually 95 - 100% of the equipment cost for baghouses (Reference 8-9). This includes the costs for foundations and supports, erection, instrumentation and controls, electrical, plumbing, painting, and freight.

Fan Replacement

When a baghouse is retrofitted to a boiler facility originally constructed without particulate controls, it is usually necessary to increase the fan capacity. This is due to the incremental pressure drop associated with baghouse operation, typically 7 in WC (Reference 13). Fan capacity may be increased by adding on a booster fan in series with the original equipment or, more conventionally, by replacing the existing fan.

In most boiler facilities retrofitted with baghouses for fine particulate control, a fan capable of handling 15 to 20 in WC back pressure at the design gas flow rate will be needed. Costs for carbon steel fans with this head capacity, plus 25% over design allowance, are shown in Figure 2. These costs include fan wheels and shafts, electric motors and controls, inlet boxes and dampers, cooled bearings with vibration and temperature sensors, couplings and interconnecting ductwork.

Installation costs for fans are relatively independent of size. Fan installation usually requires 6 to 8 man-weeks labor effort and a crane for 1/2 to 2 days. The cost is usually less than $20,000 to $30,000, including structural and electrical work plus crane rental.

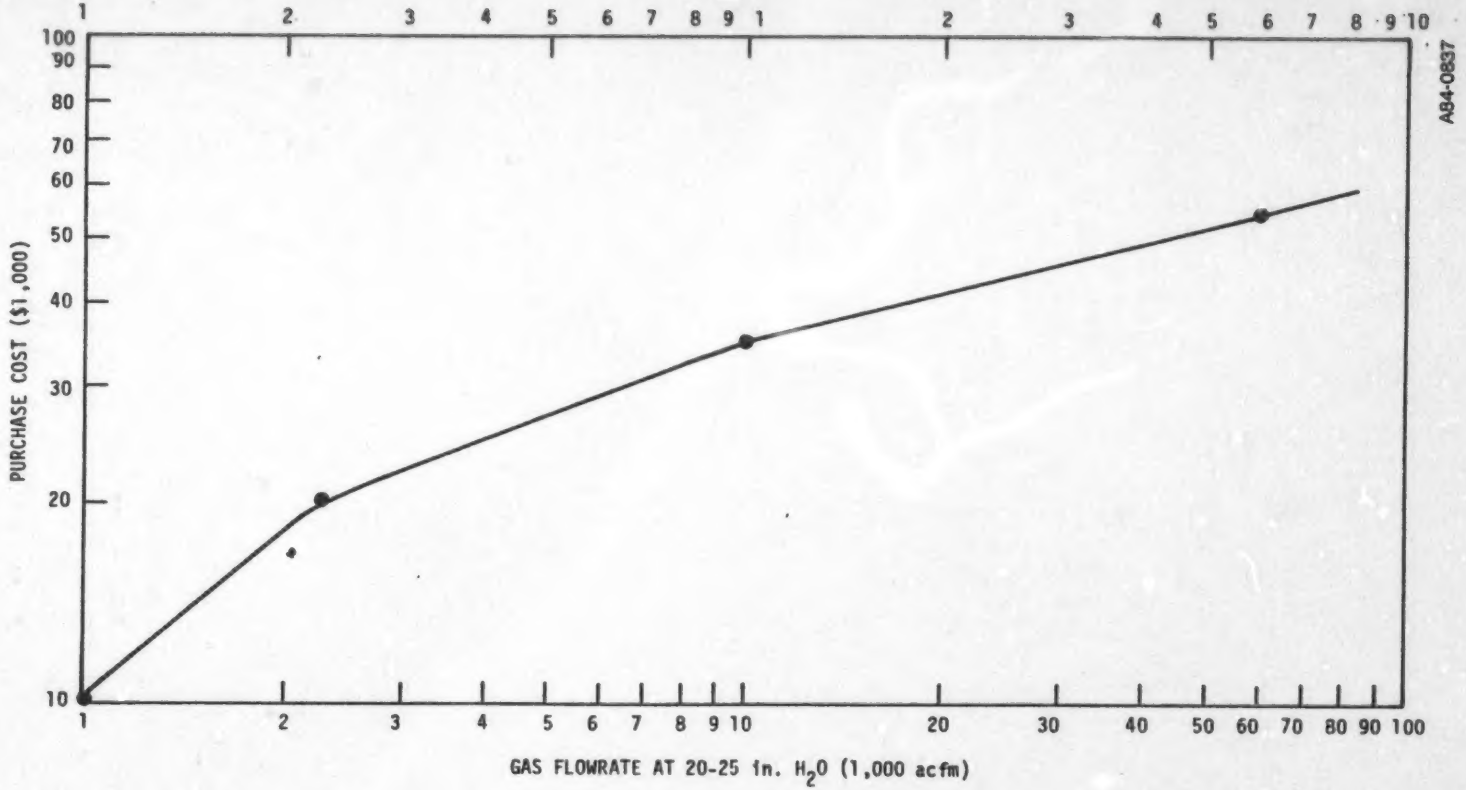

Figure 2. Purchase Cost of Carbon Steel Fans (July 1982)

Venturi Scrubber/Acid Gas Absorber Systems

Figure 3 presents a schematic of a typical venturi scrubber/acid gas absorber system for control of fine particulate and HCl emissions. This system includes a small nickel-alloy quench to reduce the temperature of the boiler exit gas to saturation, a high nickel alloy venturi scrubber, a cyclonic separator and integral packed tower absorber of fiberglass construction, polypropylene tower packing, a caustic recycle system, a corrosion-resistant fan, and an acid-resistant stack. This type of system would be preferred in cases where wastes containing significant quantities of ash and/or chlorine are to be co-fired.

Total equipment costs for this generic system are presented in Figure 4. These costs are based on the assumption of a 30-in WC venturi pressure drop, which would be typical for hazardous liquid waste co-firing.

If no venturi scrubber is needed (i.e., little or no particulate control problem), the total equipment cost for the system is reduced by approximately 15%.

Installation costs including freight for this type of scrubbing system are typically about 55% of the equipment cost.

INDIRECT COSTS

Indirect engineering and construction costs will be associated with any major retrofit activity such as burner system replacement/addition or APCD addition. These indirect costs are usually estimated as percentages of the total direct cost for equipment purchase and installation, as shown in Table 4.

TABLE 4. INDIRECT COST MULTIPLIERS

Indirect cost	Percentage of direct cost
Engineering and supervision	10 to 20[a]
Construction and field expenses	10 to 20[b]
Construction fee	7.5 to 10
Startup	1 to 3
Contingency	10
TOTAL	38.5 to 63

[a] 20% applies to ESP addition
[b] 20% applies to ESP or baghouse addition

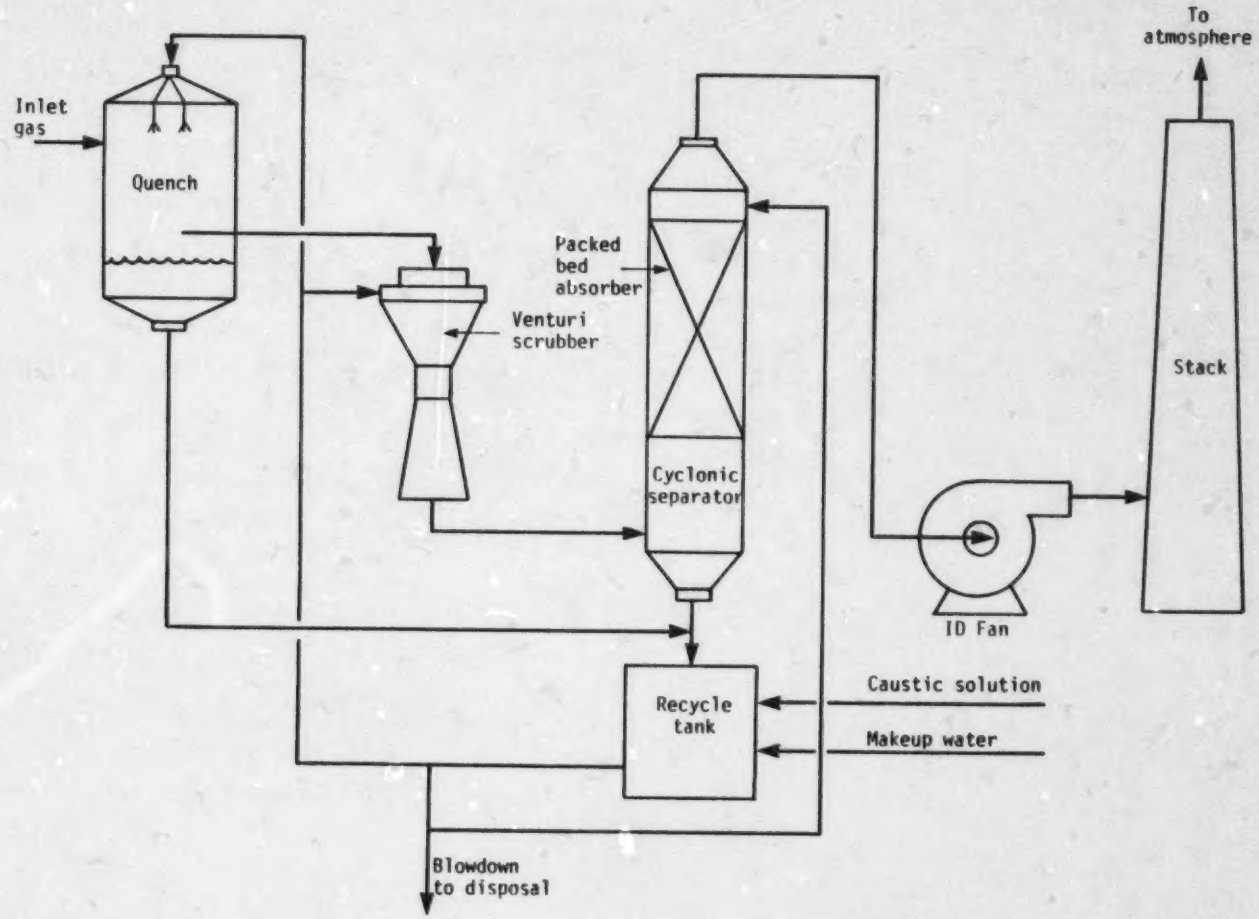

Figure 3. Generalized flow diagram for quench/scrubber system.

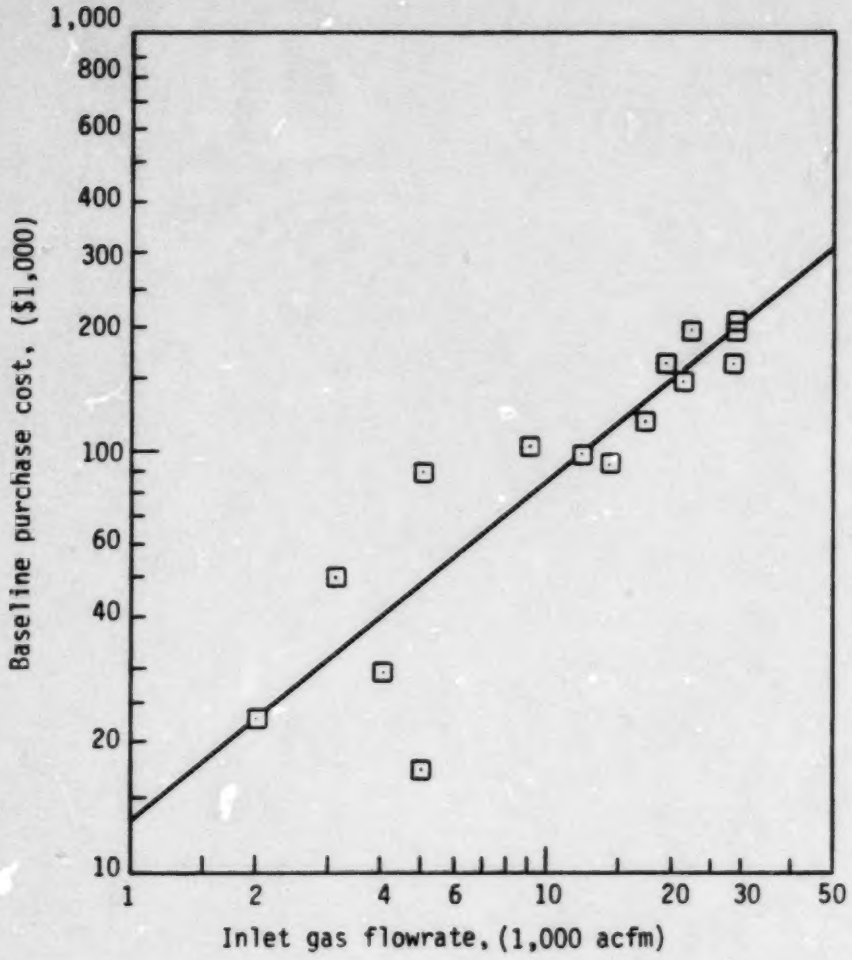

Figure 4. Purchase cost of scrubbing systems receiving 500° to 550°F gas (July 1982).

These percentages are somewhat higher than would be expected for new facility construction because they apply to retrofit situations.

SUMMARY OF CAPITAL REQUIREMENTS

Total capital requirements for retrofit can be summarized in the following format.

Waste handling equipment	
Tanks (installed)	$_____
Pumps (installed)	_____
Piping (installed)	_____
Filters (installed)	_____
Burner system modification	
Equipment	_____
Installation	_____
APCD additions	
Equipment	_____
Installation	_____
Total direct cost	$_____
Indirect cost	
Engineering and supervision	$_____
Construction and field expense	_____
Construction fee	_____
Startup	_____
Contingency	_____
Total indirect cost	$_____
TOTAL CAPITAL REQUIREMENT	$_____

SECTION 4

INCREMENTAL O&M COSTS

Incremental O&M costs for boiler operation are likely whenever waste, rather than fuel, is burned. These incremental costs can include increased consumption of electric power and water, higher costs for residue disposal and maintenance, add-on costs for scrubbing chemicals, liquid nitrogen, and waste analysis, plus capital recovery charges.

POWER

Power requirements throughout the boiler facility are changed to some extent as a result of substituting liquid waste for a fraction of the fuel originally burned. This includes power requirements for pumping, tank heating and agitation, and line heat tracing. However, any significant increases in power consumption will be related to atomizing air compressor, combustion air blower, and ID fan operation. In most cases, the costs associated with increased power consumption will be relatively minor.

Atomizing Air Compressor Power

If air is used for atomization, it is likely that additional power will be required for compressor operation when wastes with heating values less than that of fuel oil are co-fired. This assumes, of course, that oil is the primary fuel. If gas or coal is the primary fuel, it is likely that either steam or mechanical atomization would be employed to avoid purchase and installation of an air compressor simply for the purpose of waste atomization.

The fuel/waste mass feed rate differential due to co-firing is given by,

$$\Delta F = (X_Q)_W \, Q_B \, [1/(HV)_W - 1/(HV)_{FO}] \qquad (4)$$

where ΔF = lb/hr differential in fuel/waste feed rate due to co-firing

$(X_Q)_W$ = fraction of total heat input due to waste co-firing

Q_B = total Btu/hr input to boiler

$(HV)_W$ = heating value of waste, Btu/lb

$(HV)_{FO}$ = heating value of fuel oil, 19,400 Btu/lb for No. 2 fuel oil.

The differential atomizing air flowrate requirement is given by,

$$\Delta(q_{air})_{comp} = 0.109 \quad °F \tag{5}$$

where $\Delta(q_{air})_{comp}$ = differential scfm of atomizing air

This assumes a ratio of 0.5 lb atomizing air per lb feed. The differential motor horsepower requirement is then given by:

$$\Delta P_{comp} = 0.329\Delta(q_{air})_{comp} \tag{6}$$

where ΔP_{comp} = differential compressor power, hp

This assumes a compressor discharge pressure of 100 psig and a 40% isothermal compression/motor efficiency.

Combustion Air Blower Power

In most cases, waste firing requires a higher excess air rate than either natural gas or fuel oil firing. Typical excess air rates for natural gas and fuel oil (at peak conditions) are 5 to 10%, and 10 to 15%, respectively. For liquid wastes, 20 to 25% excess air is typical, and 50% excess air may be required for heterogeneous blends.

Based on the standard combustion chemistry detailed in Reference 12, combustion air requirements during co-firing can be estimated from the equations shown below.

Natural gas:

$$(F_{air})_{bl} = 7.2 \times 10^{-4} Q_{NG} \quad (1+EA) \tag{7}$$

where $(F_{air})_{bl}$ = lb/hr combustion air

Q_{NG} = Btu/hr heat input with natural gas during co-firing

EA = fractional excess air, 0.05 to 0.1

No. 2 fuel oil:

$$(F_{air})_{bl} = 7.4 \times 10^{-4} Q_{FO} \quad (1+EA) \tag{8}$$

where Q_{FO} = Btu/hr heat input with fuel oil during co-firing

Waste:

$$(F_{air})_{bl} = 4.31\,[2.664\,(X_C)_W + 7.936\,(X_{H2})_W - (X_{02})_W - 0.226\,(X_{C1})_W]\;X(Q_W/HV_W)\;(1+EA) \quad (9)$$

where $(X_C)_W$ = mass fraction carbon in waste
$(X_{H2})_W$ = mass fraction hydrogen in waste
$(X_{02})_W$ = mass fraction oxygen in waste
$(X_{C1})_W$ = mass fraction chlorine in waste
Q_W = Btu/hr heat input with waste
HV_W = Btu/lb heating value of waste
EA = 0.2 to 0.5

These expressions can be combined to estimate the differential combustion air requirement due to co-firing as shown below.

$$\Delta(F_{air})_{bl} = [(F_{air})_{bl}]_W + [F_{air})_{bl}]_F\,(1-Q_B/Q_F) \quad (10)$$

where $[(F_{air})_{bl}]_W$ = expression for waste firing
$[(F_{air})_{bl}]_F$ = expression for fuel firing
$Q_F = Q_{NG}, Q_{FO}$ = Btu/hr heat input from fuel during co-firing

Q_B = total Btu/hr heat input to the boiler from waste and fuel

Assuming a blower discharge pressure of 20 in WC and a blower/motor efficiency of 50%, the differential power requirement is given by,

$$\Delta(P_{bl}) = 1.37 \times 10^{-3}\,\Delta(F_{air})_{bl} \quad (11)$$

where $\Delta(P_{bl})$ = differential hp requirement.

ID Fan Power

The ID fan power requirement may increase as a result of waste co-firing for either of two reasons: (1) the total gas flow is increased, and/or (2) the system back pressure is increased due to APCD addition. APCD addition, specifically wet scrubbing system addition, affects the total gas flow rate and temperature as well as the overall pressure drop.

A lengthy series of calculations is required to rigorously predict the impact of waste co-firing on ID fan power consumption. The necessary equations are presented in Section 3 of Reference 12 if an accurate estimate is needed. For the purposes of this

study, however, the following shortcut method can be used so long as the fan power consumption prior to the advent of waste co-firing is known.

Assuming that the waste is primarily organic, rather than aqueous, the increase in flue gas flowrate due to co-firing will be roughly proportional to the increase in the combustion air requirement, $(F_{air})_{bl}$. The ID fan power requirement is, in turn, proportional to this increase. The ID fan power requirement is also roughly proportional to the increase in system pressure drop resulting from APCD addition. For baghouse addition, the pressure drop will generally increase by a factor of two, from approximately 5 to 10 in WC to approximately 10 to 20 in WC. For venturi scrubber/acid gas absorber addition, the pressure drop will generally increase from 5 to 10 in WC to 30 to 60 in WC, with a factor of 6 increase considered most typical.

Therefore, the incremental fan power requirement due to co-firing can be estimated from the following expression.

$$\Delta(P_{fan}) = (N_{\Delta p})\ (1+ \Delta(F_{air})_{bl}/[(F_{air})_{bl}]_{initial})\ (P_{fan})_{initial} - (P_{fan})_{initial} \quad (12)$$

where $\Delta(P_{fan})$ = incremental fan horsepower

$\Delta(F_{air})_{bl}$ = incremental lb/hr combustion air

$[(F_{air})_{bl}]_{initial}$ = lb/hr combustion air for baseline fuel firing

$(P_{fan})_{initial}$ = fan horsepower for baseline fuel firing

$N_{\Delta p}$ = relative increase in system pressure drop due to APCD addition

= 1 for ESP or no APCD addition

= 2 for baghouse addition

= 6 for venturi scrubber/absorber addition

Summary Of Incremental Power Requirement

Total incremental power requirements for waste co-firing are given (largely) by the sum of the three incremental power requirements discussed above. These estimated power consumption rates can be used in conjunction with the boiler facility operating schedule and the applicable unit cost for electricity to project annual incremental expenditures for power.

Unit costs for power demand depend on overall facility demand and plant location. Typically, unit costs for industrial users in

the continental U.S. range from 5.5 to 7.5 cents/kwh.

WATER

Generally, boiler facility water consumption will increase significantly only if a venturi scrubber and acid gas absorber are installed to control particulate and HCl emissions resulting from waste co-firing. Assuming that a caustic recycle system is employed with a nominal 5% blowdown rate, the methods presented in Reference 12 can be used to derive an accurate estimate of water consumption. For the purposes of this study, however, a makeup water requirement of 1.5 gal/1000scf of flue gas can be assumed.

Unit water costs depend on the water source, location in the U.S., and plant-wide demand. A typical range of costs for large-volume industrial users supplied by municipalities is 25 to 80 cents/1000 gal.

CAUSTIC

If HCl removal from the combustion gas is required, 50% caustic soda solution is frequently added to the scrubber system recycle flow to aid absorption and to neutralize the effluent. The consumption rate of 50% caustic soda solution is roughly 2.2 times the chlorine/chloride feed rate to the boiler. The cost for 50% solution is roughly $140/ton, or 7 cents/lb.

LIQUID NITROGEN

Liquid nitrogen is commonly used to blanket liquid waste storage tanks for safety purposes. Because normal storage losses are negligible (approx. 0.1% per day), nitrogen losses due to displacement during tank filling predominate and consumption is roughly the same as volumetric waste throughput on an annual basis.

Nitrogen costs depend largely on the consumption rate. For very small facilities burning a small amount of waste, gas cylinders may be the economic choice. The cost in this case is about $6.35/100 ft^3. For larger volume co-firing, liquid nitrogen is preferred. The cost may range from $0.65 to $1.10/100 ft^3, depending on consumption, and storage tank rental charges may total $2500 to $4000 per year.

ASH DISPOSAL

Co-firing hazardous waste with natural gas or fuel oil will in all likelihood increase the quantities of ash deposited on the furnace floor and the hopper fallout. Addition of baghouses or ESP's will also increase the quantities of ash that must be disposed. However, the major potential cost impact of hazardous

waste co-firing is in ash characteristic, rather than the quantities of ash generated.

Under current RCRA regulations for incinerators and other treatment processes, any residue (e.g., ash) from the processing of a hazardous waste is, by definition, a hazardous waste as well. If this criterion was expanded to include ash from boilers co-firing hazardous waste, the cost impact could be significant (depending, of course, on the quantity of ash handled).

Conventional sanitary landfilling costs in major industrial areas throughout the U.S. range from about 0.1 to 1.0 cents/lb for dry solid waste. Secure landfilling costs in the same areas range from 1.2 to 4.8 cents/lb for the same type of waste. Typically, the secure landfilling costs are an order-of magnitude higher than conventional landfilling costs. This cost differential, in conjunction with the near-quantitative collection of fly ash in an ESP or baghouse, could turn an insignificant cost item into a significant cost. This possibility can be evaluated by estimating the total annual cost for ash disposal using the general relationship,

Annual cost,$= (Ash content of waste, lb/lb)

x (Annual waste throughput, lb)

x (Landfilling cost, $/lb) (13)

WASTEWATER DISPOSITION

A significant increase in wastewater generation due to co-firing is unlikely unless a wet scrubbing system (venturi scrubber and absorber) is needed for particulate and HCl control. In this case, a blowdown stream will be generated with a flowrate comparable to or slightly less than the scrubber system makeup water rate previously described. In most large industrial plants co-firing hazardous wastes, this flow will be insignificant compared to the plant-wide wastewater flow and can be treated in the central facility at little or no incremental cost. The blowdown stream should be neutral and relatively innocuous, although high suspended and dissolved solids levels are probable.

OPERATING LABOR

In the case of simple boiler retrofit, no additional operating labor should be required as a result of hazardous waste co-firing. If APCD's are added, however, some additional operator time may be required. This does not necessarily mean that additional personnel need to be hired, only that more labor hours would be attributed to the boiler facility accounting cost center.

Estimated operating labor requirements for APCD systems (References 8-9) are 2-4 manhours/shift for baghouses, 0.5-2 manhours/shift for ESP's, and 2-8 manhours/shift for wet scrubbing systems. In the major industrial areas in the U.S., wages for process operators typically range from $9 to $11/hr. A burdening factor of approximately 40% should also be included to cover benefits.

MAINTENANCE

Maintenance is potentially the most significant annual cost associated with co-firing hazardous wastes in boilers, and also the most difficult to predict. Within the boiler itself, severe convective pass fouling and acid-gas corrosion are the two major concerns. These and other boiler-related maintenance problems are discussed at length in Reference 2. The major conclusion pertinent to this study is that incremental boiler maintenance due to waste co-firing can range from virtually nil to the other extreme of catastrophic tube bundle failure. This type of corrosion-related problem is most likely when chlorinated, other halogenated, or phosphorus-bearing materials are burned and economizers or air heaters are incorporated in the boiler design. Likewise, fouling problems are most likely to occur when high ash content and/or alkali metal contaminated waste are burned in boilers with narrow, staggered tube spacings in the convective passes. These generalizations are obvious; however, insufficient information is available at present to predict maintenance costs as a function of waste type and boiler design in a quantitative manner. Much more historical data on waste co-firing in boilers is needed to develop any type of quantitative relationship.

A considerably larger data base is available on APCD maintenance costs, however. Assuming that the proper type of equipment is specified for a given application, and that suitable materials of construction are used, the annual maintenance cost for ESP's and wet scrubbing systems is typically 5% of the equipment cost (References 8-9). A 5% multiplier can also be used to project hardware maintenance for baghouse systems, but the cost for bag replacement must also be considered. Typically, bags have a useful life of 1-3 years, with two years considered a reasonable average. For hazardous waste co-firing applications, however, the assumption of annual bag replacement may be more realistic. Bag cost estimating guidelines are presented in section 3 of this report.

WASTE ANALYSIS

Depending on the number and variability of wastes co-fired, analytical costs may be essentially zero or a measurable contribution to the total incremental cost. At the most, waste analyses may require half the time of one day-shift laboratory technician

to perform heating value tests, flash point tests, chlorine/chloride analysis, proximate analyses, etc. The annual costs for this labor, including burdens, is approximately $10,000 to $15,000.

CAPITAL RECOVERY

The capital recovery multiplier is calculated by the expression,

$$CRF = \frac{i(1+i)^n}{(1+i)^{n-1}} \qquad (14)$$

where CRF = capital recovery factor

i = annual interest rate

n = capital recovery period, or economic life of the system

For an interest rate of 10% and a capital recovery period of 10 years, the capital recovery factor is 0.163. Annual capital recovery charges are determined by multiplying the total capital investment (direct plus indirect costs) by this factor.

TAXES AND INSURANCE

Annual costs for taxes and insurance can be estimated as 4% of the total capital investment.

SUMMARY OF INCREMENTAL O&M COSTS

Incremental O&M costs for waste co-firing in boilers can be summarized in the following format:

Variable costs

Power	$_____/yr
Water	_____
Caustic	_____
Liquid nitrogen	_____
Ash disposal	_____

Semivariable costs

Operating labor _____

Maintenance _____

Waste analysis _____

Fixed costs

Capital recovery _____

Taxes and insurance _____

Total incremental O&M cost $_____/yr

SECTION 5

CREDITS

The credits associated with co-firing hazardous wastes include the obvious fuel savings, plus elimination of certain on-site and/or contractor costs for disposal of the waste.

FUEL SAVINGS

Unless the full capacity of the boiler is not needed to satisfy plant steam requirements, one of the basic goals of waste co-firing is to maintain the same steam flow and quality. With this situation, the energy balance expressions for baseline fuel firing and waste/fuel co-firing are:

$$Q_{F1} n_1 = Q_S \tag{15}$$

and

$$(Q_{F2} + Q_W)\, n_2 = Q_S \tag{16}$$

where Q_{F1} = heat input with fuel during baseline firing, Btu/hr

Q_{F2} = heat input with fuel during co-firing, Btu/hr

n_1 = Boiler efficiency during baseline operation, as measured by the ASME heat loss method

n_2 = efficiency during co-firing

Q_W = heat input with waste, Btu/hr

Q_S = heat output with steam, Btu/hr

The fuel savings is given by,

$$\Delta Q_F = Q_{F1} - Q_{F2} \tag{17}$$

Therefore,

$$\Delta Q_F = Q_W - Q_S\,(1/n_2 - 1/n_1) \tag{18}$$

From equation 18, it is obvious that the fractional heat input with the waste must be greater than the efficiency loss associated with co-firing in order to realize a net fuel savings. Assuming that this is the case, net fuel savings can be estimated by,

$$F_F = Q_F/HV_F \quad (19)$$

where F_F = mass or volumetric fuel conservation rate

HV_F = fuel heating value

For natural gas,

$$F_F,scfh = Q_F/1000 \quad (20)$$

For No. 2 fuel oil

$$F_F, gph = Q_F/140,000 \quad (21)$$

Based on these estimates, the boiler facility operating schedule, and local fuel prices, the annual fuel conservation credit can be calculated directly.

WASTE DISPOSAL ELIMINATION

The savings associated with elimination of the waste disposal problem are highly variable, and not always easy to estimate. Two examples are provided for illustrative purposes. However, other waste disposal scenarios may also apply.

Because the vast majority of waste candidates for boiler co-firing are combustible liquids, it is likely that the alternative form of waste disposal would be incineration, either on-site or at a commercial waste disposal facility. If the waste was burned in an on-site incinerator prior to boiler co-firing, the variable incineration costs such as auxiliary fuel, power, water, chemicals, residue disposal, labor, and maintenance would be eliminated by conversion to boiler co-firing. Fixed costs for the incineration facility would not be eliminated, however. This also assumes that all of the wastes previously incinerated are used as boiler fuel; if only the best fuel-quality wastes are co-fired, this could adversely impact incinerator operation and disposal cost for the remaining waste mix. Many factors such as these need to be considered in estimating the savings associated with elimination of alternative waste disposal operations. The analysis must be done on a site-specific basis.

If the waste was shipped to an off-site incineration facility prior to boiler co-firing, the cost analysis is more straightforward. However, estimating an across-the-board cost savings is still difficult. Commercial waste disposal firms typically charge

whatever the local market will bear, rather than a fixed percentage above cost. Moreover, most firms charge a premium for chlorine and ash content, and may offer a discount for volume and/or fuel value. Typical costs are 4 cents to 15 cents/lb, although special wastes such as PCB oils may demand a price of 30 cents/lb or even higher.

SECTION 6

COST/CREDIT SUMMARY

The costs and credits associated with hazardous waste co-firing in industrial boilers may be summarized as follows:

TOTAL CAPITAL INVESTMENT	$_____
ANNUAL O&M COSTS	$_____
ANNUAL CREDITS	
Fuel savings	_____
Waste disposal elimination	_____
Total credit	$_____
NET CREDIT/COST	$_____
ANNUAL WASTE THROUGHPUT	_____ lb
UNIT CREDIT/COST	$_____ /lb

SECTION 7

HYPOTHETICAL COST/CREDIT CALCULATIONS

This section presents cost/credit evaluations for two hypothetical co-firing scenarios. These evaluations are intended to demonstrate how the information in Sections 3-6 of this report can be used to assess the economics of hazardous waste co-firing for specific situations. Although the results indicate that co-firing is profitable in both cases, no generalization concerning co-firing economics is intended.

CASE A

Scenario Description

The subject of this evaluation is a large chemical intermediates plant located in the midwestern U.S. Among the many wastes and byproducts generated in this plant is a 2,000 lb/hr, 14 million lb/yr methacrylate bottoms stream with a higher heating value of 12,000 Btu/lb. This waste is currently disposed at a nearby commercial incineration facility at a cost of 4 cents/lb. Other than its 1% ash content, however, this waste is a prime candidate for co-firing in the plant boiler facility.

This case study addresses the incremental costs and credits associated with the switch from off-site disposal to on-site boiler co-firing. Tables 5-9 present the pertinent technical and cost information in summary form; the following subsections discuss the methods and assumptions used to develop this information, including the final cost/credit projections.

Waste/Fuel Characteristics

As indicated in Table 5, the primary fuel is No. 6 fuel oil with a higher heating value of 18,500 Btu/lb. Prior to co-firing, this was the sole source of energy for steam generation. The waste is a methacrylate distillation bottoms stream with a heating value of 12,000 Btu/lb and generally desirable fuel qualities,

TABLE 5. CASE A-FUEL/WASTE CHARACTERISTICS

Parameter	No. 6 Fuel Oil	Waste
Carbon, %	88.0	60.0
Hydrogen, %	11.0	9.0
Oxygen, %	-[a]	28.0
Nitrogen, %	0.5	-[a]
Sulfur, %	0.5	-[a]
Water, %	-[a]	2.0
Ash, %	-[a]	1.0
Heating value, Btu/lb	18,500	12,000

[a]Negligible; much less than 0.5%

except for its 1% ash content. The large elemental oxygen content of the waste is primarily responsible for its heating value differential from that of No. 6 fuel oil.

Boiler Design and Operating Characteristics

The boiler in question is a balanced draft, packaged watertube design which generates 250 psig saturated steam for process heating purposes. The design steam capacity is 100,000 lb/hr, although the average load is 80,000 lb/hr. This boiler is equipped with four single register, combination gas/oil burners designed for high pressure air atomization. Normally, all 4 burners fire No. 6 fuel oil at an average excess air level of 10%.

Combustion gas exits the boiler convective passes at 650°F, and enters an economizer which further reduces the gas temperature to 350°F. This gas is ducted directly to an ID fan and stack; no APCD's are included in the original design because particulate emissions are well below the applicable local standard of 0.03 gr/dscf.

Under these baseline fuel firing conditions, the overall boiler efficiency is 86.0% based on standard ASME heat loss calculations. This requires a No. 6 fuel oil feed rate of 5096 lb/hr, or 637 gph.

In order to accommodate the 14 million lb of methacrylate waste generated annually, it is necessary to co-fire this material at a rate of 2000 lb/hr over a period of 7000 hr/yr, which corresponds to the annual on-stream time for the production process. This means that one of the four fuel oil burners must be

TABLE 6. CASE A-BOILER DESIGN AND OPERATING CHARACTERISTICS

Parameter	Baseline fuel firing	Waste co-firing
Basic design	Watertube, balanced draft, with economizer	same
Burner system	4 single register gas/oil	same
APCD system	None	ESP(insulated)
Waste storage	None	1-5000 gal tank
Steam pressure, psig	250 sat	250 sat
Steam capacity, 10^3lb/hr	100.0	99.4
Ave. steam load, 10^3lb/hr	80.0	80.0
Heat output, 10^6Btu/hr	81.1	81.1
Mass feed rate, lb/hr		
Fuel	5,096	3,836
Waste	0	2,000
Total	5,096	5,836
Volumetric feed rate, gph		
Fuel	637	480
Waste	0	263
Heat input, 10^6Btu/hr		
Fuel	94.3	71.0
Waste	0	24.0
Total	94.3	95.0
Heat input, with waste, %	0	25.3
Boiler efficiency, %	86.0	85.4
Excess air, %		
Fuel	10	10
Waste	-	25
Total air flow, 10^3lb/hr	77.8	80.5
Combustion gas temp., °F[a]	350	350
Combustion gas flow. 10^3lb/hr	84.0	87.4
10^3 acfm[a]	28.5	29.8
10^3 dscfm	16.2	16.8
Particulate loading, gr/dscf		
ESP inlet	-	0.14
ESP outlet[b]	-	0.03
Required removal efficiency, %	-	78.4
Annual on-stream time, hrs/yr	7000	7000

[a]Economizer outlet temperature

[b]Applicable particulate standard

TABLE 7. CASE A - CAPITAL REQUIREMENTS

Item	Cost, $
Waste handling equipment	
Tanks (installed)	34,000
Pumps (installed)	2,500
Piping (installed)	4,400
Filters (installed)	1,000
Burner system modifications	-0-
APCD additions	
Basic ESP	300,000
Installation & auxilliaries	300,000
Total direct cost	641,900
Indirect costs	
Engineering & supervision	130,000
Construction & field expense	130,000
Construction fee	64,000
Startup	13,000
Contingency	64,000
Total indirect cost	401,000
TOTAL CAPITAL COST	1,042,900

TABLE 8. CASE A - INCREMENTAL O&M COSTS

Item	Incremental Cost, $/yr
Power	11,400
Water	-0-
Caustic	-0-
Liquid nitrogen	5,200
Ash disposal	2,500
Wastewater	-0-
Operating labor	12,250
Maintenance	15,000
Waste analysis	-0-
Capital recovery	170,000
Taxes & insurance	41,700
TOTAL COST	258,000

TABLE 9. CASE A - OVERALL COST/CREDIT SUMMARY

Item	Cost/credit
Total capital investment	$1,000,000
Annual O&M costs	$ 258,000
Annual credits	
Fuel savings	$ 937,000
Waste disposal elimination	$ 560,000
Total credit	$1,497,000
Net credit	$1,239,000
Annual waste throughput	14,000,000 lb
Unit credit	$0.0885/lb

devoted to waste firing.

Because the methacrylate waste is similar to preheated No. 6 fuel oil in terms of handling characteristics, no significant burner system modifications are required. For the baseline, 80,000 lb/hr steam generation rate, each burner fires No. 6 fuel oil at a rate of 1,274 lb/hr, or more importantly, 23.6 million Btu/hr. The 2000 lb/hr waste firing rate is equivalent to 24 million Btu/hr, hence, the fuel-to-waste substitution is insignificant in terms of heat input for the one burner affected. Waste co-firing accounts for about 25% of the total heat input. However, other aspects of boiler operation are impacted by waste co-firing.

First, the waste heating value is 12,000 Btu/lb, compared to 18,500 Btu/lb for No. 6 fuel oil. Thus, a lb per lb tradeoff of waste for fuel oil is not possible. Second, the heterogeneity of the waste requires an excess air level of 25% for the single waste burner, compared to 10% for the three fuel oil burners. As a result, the total combustion air requirement and combustion gas flow rate are increased slightly.

The combination of these factors reduces the overall boiler efficiency to 85.4% during waste co-firing, compared to 86.0% during baseline fuel firing. It is still possible to maintain the average steam load of 80,000 lb/hr and the desired temperature

profile throughout the system; however, this necessitates a fuel oil feed rate of 3,836 lb/hr during waste co-firing, versus the 3,096 lb/hr fuel oil feed rate for ideal waste/fuel substitution. Nevertheless, this fuel savings is a substantial 1,260 lb/hr, or 157 gph.

The other major aspect of boiler operation impacted by waste co-firing is air emssion control. During baseline fuel firing, particulate emissions are negligible. During waste co-firing, however, the particulate loading in the boiler exit gas is approximately 0.14 gr/dscf, based on (1) the 1% ash content of the waste and 2000 lb/hr waste feed rate, and (2) standard combustion gas flow rate calculations (Reference 12). With the applicable particulate standard of 0.03 gr/dscf, an approximate removal efficiency of 80% is required. This is best accomplished by addition of an ESP between the economizer section of the boiler and the ID fan.

Capital Requirements

The capital retrofit requirements for waste co-firing include the addition of waste storage/handling equipment and the addition of an ESP for particulate control. Burner system modifications are insignificant--simple replumbing of one burner for waste firing. Because the combustion gas flow increase during co-firing and the ESP pressure drop are insignificant, the existing ID fan and stack are adequate.

Waste storage/handling equipment additions include:

(1) One 5000-gal waste tank, which will provide 19-hr holding capacity. The installed cost for this tank, presented in Table 7, is based on the design criteria specified in Section 3 of this report.

(2) Two 10 gpm gear pumps for waste feeding. The cost presented in Table 7 includes complete installation.

(3) 200 ft of 1 in black pipe plus fittings, at an installed cost of $22/ft.

(4) Two inline basket strainers and carbon steel housing, installed.

The basic ESP equipment cost is calculated from Equation 2, for insulated ESP's. Insulation is required to prevent dewpoint condensation, given the 350°F economizer outlet temperature. The ESP sizing is based on a gas flow rate 25% greater than that reported in Table 6 for waste co-firing, and a particulate removal efficiency of 90%. The 25% gas flow safety factor reflects the differential between the 100,000 lb steam/hr design rate and the

average 80,000 lb/hr steam rate, on which the gas flow rates in Table 6 are based. The 90% particulate collection efficiency specification, vs. the 80% requirement, provides a safety margin for changes in feed composition and regulatory requirements. Particle drift velocity in Equation 3 is an assumed 0.1 ft/s.

The ESP installation cost estimate, and the indirect construction costs, are based on information provided in Section 3.

Incremental O&M Costs

Incremental O&M costs due to waste co-firing include increased power demand, liquid nitrogen consumption for waste tank blanketing, ash disposal, operating labor and maintenance for the ESP system, capital recovery charges, and additional taxes/ insurance. The cost estimates for APCD maintenance, capital recovery, and taxes/insurance in Table 8 are based on the standard multipliers given in Section 4. Other incremental O&M cost derivations are discussed below.

The total incremental power demand is 33.6 hp: 26.5 hp for atomizing air compressor operation, 3.7 hp for the combustion air blower, and 3.4 hp for the ID fan. These estimated values are based on the flow rate differentials for waste co-firing vs. baseline fuel firing, and Equations 4-12 in Section 4.

The liquid nitrogen requirement is equivalent to the waste throughput rate, because only tank filling losses are significant. This requirement is 246,000 ft^3/yr, at a unit cost of $1.10/100 ft. A $2500 storage tank rental charge is also applied.

At a waste firing rate of 2000 lb/hr, ash content of 1%, 7000 hr/yr co-firing operation, and 90% particulate collection efficiency, the annual ash generation rate is 126,000 lb. The disposal cost for this ash is approximately 2 cents/ lb.

The incremental labor requirement for the ESP installation is an estimated 1 manhour per 8-hour shift, or 875 hr/yr. The hourly labor cost is $14, including a 40% burdening factor.

Credits

The annual fuel savings credit of $937,000 is based on the fuel conservation rate of 157.5 gph, 7000 hr/yr operation under co-firing conditions, and a fuel oil price of $0.85/gal. In addition to this fuel credit, a $560,000/yr cost for off-site waste disposal is avoided. This figure is based on a 4 cents/lb disposal charge for the 14 million lb of waste generated annually.

Overall Cost/Credit Summary

For this hypothetical case, waste co-firing is an extremely attractive alternative to off-site waste disposal. The fuel savings alone provide a net credit of nearly $700,000/yr. Including waste disposal cost elimination, the annual savings is $1.2 million. This yields a payback period of less than 1 year for the initial $1 million investment.

CASE B

Scenario Description

The subject of this evaluation is a small chemical processing plant, also located in the Midwest. This plant generates approximately 500 lb/hr (65-70 gph) of liquid waste, primarily methanol and dirty solvents, along with a larger quantity of solid waste. Both the liquid and solid wastes are currently disposed off-site at an average cost of 5 cents/lb. However, the liquid waste is a reasonably good candidate for boiler co-firing, despite the fact that it contains some chlorine and ash. Tables 10-14 summarize the technical information, retrofit costs, annual O&M costs, and credits associated with co-firing this waste in an on-site boiler for process steam generation, as an alternative to off-site disposal.

Waste/Fuel Characteristics

As indicated in Table 10, the primary fuel is natural gas with a heating value of 1000 Btu/scf. This is the only fuel accommodated by the original boiler design.

The waste is a mixture of methanol and other solvents containing 91.5% organics, 8.0% water, and 0.5% ash. A fraction of the organic solvent mix is chlorinated, accounting for the 4.0% chlorine content. The heating value of this waste is 10,000 Btu/lb, approximately half that of the primary fuel due to the presence of organically bound oxygen and chlorine, and the 8% solubilized water.

Boiler Design and Operating Characteristics

The boiler in question is a small, forced draft, firetube unit with no economizer, air heater, or APCD's. It is used to generate 125 psig saturated steam for process heating purposes. The design steam capacity is 10,000 lb/hr, although the normal load (with very little fluctuation) is 9,000 lb/hr.

The boiler was originally designed with a single ring burner for natural gas. Prior to modification for co-firing, gas was fired through the burner at a rate of 11,900 scfh with 5% excess air to generate the desired 9,000 lb/hr of steam. Combustion gas

TABLE 10. CASE B - FUEL/WASTE CHARACTERISTICS

Parameter	Natural gas	Waste
Carbon, %	69.3	42.0
Hydrogen, %	22.7	10.5
Oxygen, %	-[a]	35.0
Nitrogen, %	8.0	-[a]
Chlorine, %	-[a]	4.0
Water, %	-[a]	8.0
Ash, %	-[a]	0.5
Higher heating value, Btu/lb	21,800[b]	10,000

[a]Negligible; much less than 0.5%

[b]Equivalent to 1000 Btu/scf

exited the boiler tubes at 550°F, yielding an overall efficiency of 75.8%.

In order to modify this unit for liquid waste co-firing, it is necessary to replace the existing burner system with a combination gas/liquid fuel burner system capable of firing the waste in question along with natural gas. The 10,000 Btu/lb waste mix is burned at a rate of 500 lb/hr, yielding a gross heat input rate of 5 million Btu/hr. In order to maintain the desired steam generation rate and temperature profile, it is necessary to co-fire 7070 scfh of natural gas, providing an additional 7 million Btu/hr heat input. Thus, the waste provides approximately 40% of the total heat input.

If perfect waste-for-fuel substitution was achieved, the 5 million Btu/hr waste feed rate would reduce the natural gas requirement by 5000 scfh. The actual reduction is about 4800 scfh, due to the lower thermal efficiency associated with waste co-firing. This inefficiency is due to (1) the non-fuel constituents of the waste (e.g., water), and (2) the fact that 20% excess air is needed for waste combustion, compared to 5% for natural gas. The combination of these two factors reduces the overall boiler efficiency from 75.8% for baseline fuel firing to 74.9% for waste co-firing.

Unlike baseline natural gas firing, waste co-firing results in significant particulate and HCl emissions. The estimated particulate loading and HCl emission rate (uncontrolled) are 0.15 gr/dscf and 20 lb/hr, respectively, both of which violate the ap-

TABLE 11. CASE B-BOILER DESIGN AND OPERATING CHARACTERISTICS

Parameter	Baseline fuel firing	Waste co-firing
Basic design	Firetube, forced draft	same
Burner system	1 gas only	1 gas/liquid fuel
APCD system	None	Wet scrubber
Waste storage	None	1-5000 gal tank
Steam pressure, psig	125 sat	125 sat
Steam capacity, 10^3lb/hr	10.0	9.9
Ave. steam load, 10^3lb/hr	9.0	9.0
Heat output, 10^6Btu/hr	9.04	9.04
Mass feed rate, lb/hr		
Fuel	547	325
Waste	0	500
Total	547	825
Volumetric feed rate		
Fuel, 10^3scfh	11.9	7.07
Waste, gph	0	66.7
Heat input, 10^6Btu/hr		
Fuel	11.9	7.07
Waste	0	5.0
Total	11.9	12.07
Heat input, with waste, %	0	41.4
Boiler efficiency, %	75.8	74.9
Excess air, %		
Fuel	5	5
Waste	-	20
Total air flow, 10^3lb/hr	9.03	9.48
Combustion gas temp.,°F		
Boiler exit	550	550
APCD exit	-	155 (sat)
Combustion gas flow, 10^3lb/hr		
Boiler exit	9.70	10.4
APCD exit	-	11.5
Combustion gas flow, 10^3acfm		
Boiler exit	4.33	4.62
APCD exit	-	3.27
Combustion gas flow, 10^3dscfm	1.80	1.92
Particulate loading, gr/dscf		
Boiler exit	-	0.15
APCD exit[a]	-	0.03
Required removal efficiency, %	-	80.0
HCl removal efficiency, %	-	99.0
Annual on-stream time, hrs/yr	7000	7000

[a] Applicable standard

TABLE 12. CASE B - CAPITAL REQUIREMENTS

Item	Cost, $
Waste handling equipment	
Tanks (installed)	34,000
Pumps (installed)	2,000
Piping (installed)	2,200
Filters (installed)	500
Burner system modifications	
Complete burner system	24,000
Installation	24,000
APCD additions	
Complete wet scrubbing system	50,000
Installation	27,000
Total direct cost	163,700
Indirect costs	
Engineering & supervision	16,000
Construction & field expense	16,000
Construction fee	16,000
Startup	5,000
Contingency	16,000
Total indirect cost	69,000
TOTAL CAPITAL COST	232,700

TABLE 13. CASE B - INCREMENTAL O&M COSTS

Item	Incremental Cost, $/yr
Power	20,000
Water	1,800
Caustic	22,200
Liquid nitrogen	3,200
Ash disposal	-0-
Wastewater	-0-
Operating labor	49,000
Maintenance *	2,500
Waste analysis	-0-
Capital recovery	37,900
Taxes & insurance	9,300
TOTAL COST	145,900

* Does not include maintenance costs for ash fouling and HCl corrosion.

TABLE 14. CASE B - OVERALL COST/CREDIT SUMMARY

Item	Cost/credit
Total capital investment	$ 230,000
Annual O&M costs	$ 146,000
Annual credits	
Fuel savings	$ 165,000
Waste disposal elimination	$ 175,000
Total credit	$ 340,000
Net credit	$ 194,000
Annual waste throughput	3,500,000 lb
Unit credit	$0.0554/lb

plicable standards. Required removal efficiencies are 80% for particulate and 99% for HCl.

These emission control requirements are best achieved using a wet scrubbing system such as that shown in Figure 3 of this report. This system includes a quench for gas temperature reduction, a venturi scrubber for particulate control, an absorption column and caustic recycle system for HCl removal and neutralization, an ID fan, and a stack. The temperature of the combustion gas is reduced from 550°F at the boiler exit to the saturation temperature of 155°F in this system. Total gas pressure drop increases from about 8 in WC, across the furnace and boiler, to about 45-50 in WC across the furnace, boiler, and scrubbing system. Thus, the ID fan is needed even though the boiler was originally designed for forced draft operation.

Capital Requirements

Retrofit requirements for this co-firing scenario include addition of waste storage and handling equipment, substantial burner system modification and addition of the wet scrubbing system previously described. Estimated costs for these additions are presented in Table 12.

At the established feed rate of 67 gph, one 5000 gal tank provides ample 3-day storage for waste. The installed cost for this tank is approximately $34,000, based on the design criteria listed in Section 3. Installed costs for the other waste handling equipment include two 5 gpm gear pumps with motors and starters,

100 ft of 1-in black pipe with valves and fittings, and two in-line basket strainers with carbon steel housings.

The "complete burner system" listed in Table 12 includes a combination gas/liquid fuel burner assembly with pilot, spark igniter, and damper, an FD blower, and master controls for flame safeguard, fuel modulation, air pressure and flow regulation. Modification of the original burner is conceivable in this case. however, complete burner and control system replacement is assumed because of the substantial changes required. These include conversion from gas only to simultaneous gas/liquid fuel firing and conversion from forced draft to balanced draft operation.

The estimated burner equipment cost in Table 12 is based on Figure 1 and a design waste feed rate of 75 gph. Installation is assumed to run 100% of this equipment cost, due to potential retrofit difficulties.

The purchase cost for the wet scrubbing system is based on Figure 4 and a design gas flow rate of 5100 acfm at the boiler exit. This includes a 10% allowance for peak steam production demand. Installation and freight costs are taken as 55% of the purchase cost.

As for Case A, the indirect cost estimates are based on direct cost multipliers listed in Table 4.

Incremental O&M Costs

In this co-firing scenario, incremental costs are incurred for power, water, caustic, liquid nitrogen, labor, maintenance, capital recovery, and insurance/taxes. The fixed costs -- capital recovery, taxes, and insurance -- are estimated by the guidelines presented in Section 4 of this report. Maintenance costs are also estimated as a fixed percentage of the capital investment, as indicated in Section 4. However, it should be noted that potential ash fouling and HCl corrosion problems in the boiler are not included in this maintenance cost estimate. The 550° F boiler exit gas temperature should preclude dewpoint corrosion, however, high temperature chlorine corrosion is still a potential problem (Reference 2). This type of unusual, and potentially extreme, maintenance problem is difficult to predict apriori. Therefore, no quantitative estimate is provide in this case study.

The power requirements for boiler system operation are increased substantially by conversion to waste co-firing. The contributing factors are compressed air requirements for waste atomization (zero when only natural gas is burned), ID fan power consumption, and, to a lesser degree, scrubber system pump operation.

Based on the 500 lb/hr waste feed rate and Equations 4-6, the atomizing air compressor power requirement is 18 hp. This could be eliminated by designing for steam rather than air atomization, however, this would have a secondary efficiency impact on a small boiler such as the one in question. Thus, a cost tradeoff exists. Air atomization is assumed for the purpose of this study.

The net increase for combustion air blower/ID fan power on conversion to waste co-firing is 38 hp. This is based on the air and combustion gas flow rates given in Table 11, the six-fold increase in system pressure drop due to scrubber addition, and Equations 7-12. In actuality, the combustion air blower power demand is reduced by conversion from forced draft to balanced draft operation. However, this is more than offset by the ID fan power requirements.

Although not discussed in Section 4, power for scrubbing system pump operation can measurably contribute to the total incremental power requirement in small facilities. In this case, the pump power requirement is 3 hp, bringing the total incremental demand to 59 hp, or 44 kw. At 7000 hr/yr operation and 6.5 cents/kwh, the incremental cost for power is $20,000, as listed in Table 13.

Section 4 of this report specifies a typical makeup water requirement of 1.5 gal/1000 acf of combustion gas for wet scrubbing system operation. In this case, the actual requirement is 1.34 gal/1000 acf of boiler exit gas, or 6.2 gpm. The annual cost for this makeup water is $1,800, assuming 7000 hr/yr operation and a $0.70/1000 gal municipal water charge.

A 50% solution of caustic soda in water is added to the scrubber system recycle basin in order to improve HCl collection efficiency, reduce hydraulic loading, and neutralize the otherwise acidic blowdown stream. The caustic soda solution feed requirement for neutralization is approximately 45 lb/hr, based on the 20 lb/hr emission rate. At 7 cents/lb and 7000 hr/yr operation, this results in an annual cost of $22,200.

The liquid nitrogen consumption rate for waste tank blanketing is about 62,400 ft^3/yr, equivalent to the annual volumetric waste throughput. For this usage rate, the cost for liquid nitrogen is approximately $1.10/100 ft^3, plus a $2500/yr storage tank rental charge.

Due to the addition of the wet scrubbing system, operating labor requirements are increased by 4 manhours/ shift, or 3500 manhours/yr. At a burdened labor cost of $14/hr, this requires an incremental expenditure of $49,000 for operating labor.

Credits

The natural gas savings due to waste co-firing is nearly 34 million scf/yr. At a unit cost of $4.85/1000 scf, this provides a $165,000 annual fuel credit. The waste disposal cost savings is $175,000/yr, based on an alternative charge of 5 cents/lb for the 3.5 million lb of liquid waste generated annually.

Overall Cost/Credit Summary

In this hypothetical scenario, waste co-firing is an attractive alternative to off-site disposal assuming that no significant boiler maintenance problems are encountered. The net annual credit is nearly $200,000, providing a payback period of 14 months for the initial $230,000 investment.

However, the payback based on fuel savings alone is marginal; less than $20,000/yr or 8.3% ROI. This might not justify the initial capital investment if the waste was initially being burned in an on-site incinerator, rather than disposed off-site.

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